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A Critical Evaluation of a Steamflood Pilot in a Deep Heavy Carbonate Reservoir in Ikiztepe Field, Turkey

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Abstract

This paper presents an evaluation of a 4,430-ft deep steamflood pilot being carried out jointly by the Japan National Oil Corporation (JNOC) and Turkish Petroleum Corporation (TPAO) in collaboration with the Japan EOR Research Association (JEORA) in the Sinan heavy oil reservoir of the Ikiztepe field, Turkey. The paper discusses pilot operations and performance highlighting the problems and the corresponding remedial measures/solutions adopted. Also presented is a discussion of results of an integrated simulation history match study. The pilot is in its final phase, and has so far yielded oil-steam ratios (OSR) of 3.42 and 0.32 during the initial cyclic steam stimulation phase and the steamflood, respectively.

Introduction

Among thermal EOR processes, the steamflooding has been the most prolific both in terms of the oil production and field applications (*Oil & Gas J., Sept. 26, 1994*). Chu[1] has summarized 28 major steamfloods which are being carried out or completed -- mostly in sandstone formations. Only a few of them yielded an OSR > 0.2. Thirteen projects have been in the field-scale, and data suggest that, for a steamflood to be successful, the reservoir should be shallower (<4000 ft) with an oil transmissibility (k_oh/μ_o) and content (ϕS_o) greater than 5 md·ft/cp and 0.08, respectively.

With the exception of Shell's Brea steamflood, no steamflood has been reported at a depth over 5000 ft. For carbonate reservoirs, the deepest steamflood reported[2] is the Lacq Superieur flood , Algeria at a depth of 2,300 ft.

There are many heavy oil reservoirs in the south-eastern Turkey, with an oil-in-place estimated at 2.5 billion STB. Therefore, primary objective of this project was to evaluate the potential of the thermal methods in enhancing oil recovery from such reservoirs.

Location and Geology

Since 1987, the JNOC and TPAO have been involved in the steamflood pilot project in the Ikiztepe field, Turkey in collaboration with JEORA. The field is located in south-eastern Turkey on the southern flank of the Taraus belt (see Figure 1). The 4430-ft deep target formation is the Sinan limestone of tertiary-cretaceous age, and is occasionally dolomitic and irregularly vuggy and fissured. The total Ikiztepe field production had been dismally low at 88 MSTB of an OOIP of 127 MMSTB due to the low oil mobility (high μ_o), rapid decline rate and a high water-cut. There exists a thin gas zone (≈10 ft) but it is not strong enough to resist the rapid decline rate. The estimated GOC, WOC and other relevant reservoir data are provided in Table 1.

The oil is heavy (10-12° API), and before the steamflood, only four wells were on production for about 4-5 years with an average oil rate of 10-20 STB/D. The initial solution GOR was estimated to be 95 SCF/STB and the measured oil viscosity under the reservoir conditions of 1841 psi and 120 °F was 936 cp. The oil viscosity sharply increases as the solution gas is released, and exceeds 2000 cp at the stock tank conditions.

Some core-derived porosity data are available from the top three of eight zones and they match reasonably well with log-derived porosities. The average porosity within the zone of interest is 15-23%. However, it was difficult to estimate the permeability as the slow separation of the solution gas resulted in a 2-5 fold increase in the oil viscosity. Nevertheless, based on the ϕ-k relationship, the average permeability was estimated to be within 50-400 md.

Pilot Operations

Feasibility Study. The feasibility study was based on available geological data, results of a simulation study with the primary production history, and some follow-up laboratory studies to characterize the rock-fluid properties.

Three processes: gas injection, high pressure CO_2 flood and steamflood were considered and sensitivity analyses were carried out for each process. The gas injection process was ruled out due to the adverse mobility ratio which would have resulted in a lower sweep efficiency. A high CO_2-oil solubility suggested that a high oil recovery could be possible, and a CO_2 pilot was initiated in a neighboring area of the field.

Selection of Target Zone. For our pilot area, the feasibility study suggested that a steamflood would be amenable to Upper Porous (UP) Sinan zone. This zone is further subdivided into three sub-zones: Upper (UP-U), Good (UP-G) and Lower (UP-L) as indicated in the stratigraphic interwell correlation given in Figure 2. UP-L is very tight within the pilot area and is assumed to have no communication with UP-G. The UP-U itself has two layers, designated as A and B. Thus, three layers: UP-U-A, UP-U-B and UP-G are chosen for the steamflood. The formation is gently dipping towards the south. The overlying and underlying tight and dense limestone stones (identified as TD and UD in Figure 2) acted as cap and base rocks. It was estimated that a steamflood would enhance the oil recovery by 18% compared to only < 1% by the natural depletion. Accordingly, UP-U and UP-G zones were targeted for the steamflood pilot.

Well Locations and Pattern. The work on pilot commenced in 1988. An inverted 5-spot pattern as shown in Figure 3 was adopted with an observation well, SO. Four corner producers: SP1, SP2, SP3 and SP4 were drilled. Recently, an evaluation well, SE, has been drilled to further investigate the temperature and water saturation distributions around the fracture connecting wells SP1 and SI. All wells are equipped with bottomhole temperature (BHT) and bottomhole pressure (BHP) monitoring devices.

Well Completions. As indicated in Figure 3, the steam injection is conducted through the central well, SI. The completion schematics of the injector, producer and observation wells are shown in Figure 4. SI well was completed with a 4½" OD insulated tubing with a V-grip MJS thermal packer set at 4331 ft to reduce the wellbore heat losses. Also, it was cemented with high-temperature cement. Relevant thermal properties are provided in Table 2.

Following drilling, an acidizing job was performed at SP1 to improve near-wellbore flow conductivity; but, it resulted in a fracture between SI and SP1. This caused an immediate wellhead pressure drop at SP1, and production of some acidizing fluids at SI. The tracer surveys also confirmed the communication between SI and SP1 through the fracture. Therefore, SP1 was completed as an observation well instead. (Subsequent steam injection during cyclic steam stimulation through SI, too, resulted in an almost immediate pressure responses at SP1.)

Surface Facilities. The schematic layout of the surface facilities are given in Figure 5. The steam is generated 0.7 kms from the injection well, SI and is supplied via an insulated surface line. The feed water for the boiler is drawn from the Selmo sandstone formation through two wells (depths: 330-ft and 660-ft) at a total rate of 5300 BPD. Properties of the feed water and key generator specifications are provided in Table 3. The field gas from the neighboring Camurlu field is used to fire the steam boiler. On average, it has been possible to generate steam of 80% or above quality.

On the production-end, the produced fluids (oil, gas and water) are collected and measured at the oil collecting station. After that, the crude oil is transported by tanker-trucks to the refinery. The waste water is treated and disposed.

Current Operations. The mandate set forth for this collaborative project being nearly fulfilled, the project will soon be terminated after the analysis of data gathered through the newly drilled evaluation well, SE. Cores obtained from the 4370ft-4495ft (1334m-1370m) zone in the well SE are being analyzed and a suite of well logs are planned. A preliminary study of the temperature-CCL log ran in SE well indicates some interesting anomalies with regard to the temperature-depth distribution. This is being discussed further later in the paper.

Pilot Performance History

The pilot performance in terms fluid production and injection histories is depicted through Figures 6-10 for the period April, 1993 - March, 1995. As with most steamfloods, the SI well was subjected to three cycles of steam stimulation before the start of the continuous steam injection. Data from these cycles are also incorporated in these figures. Also included are data for SI well which was put on production during April-May, 1994 when the steam injection was suspended.

Cyclic Steam Stimulation (CSS). The CSS was initiated at a steam rate of 72 CWE BPD, and it was later increased to 216 CWE BPD. The steam injection pressure was maintained below 2500 psig to avoid any fracturing of the formation. Also, to avoid thermal damage to the cementation and the packer elements, the BHT at SP1was not allowed to exceed 275°F. While the BHT at other wells did not increase, the BHT at well SP1 showed a marked increase from 50°C (122°F) to 118°C (244°F) during the second cycle of the CSS confirming, yet again, the communication through the fracture. As SP1 was not completed with thermal cement and packer, it was decided to plug it back to prevent any possible well damage by heat.

In summary, the three cycles of CSS at SI between April-September, 1993 produced oil at an average rate of 40-50 STB/D. The total oil recovery during the CSS was 4,315 STB at the expense of 1,260 CWE bbl of steam (i.e., OSR= 3.42).

Steamflood. Continuous steam injection started in October, 1993 at a low initial rate of 210 CWE BPD to satisfy the limitation of 2500 psi on the injection pressure -- set so as not to exceed the formation fracturing pressure. However, this operational constraint resulted in a very poor steam injectivity; as a result, by November, 1994, the injection rate had to be increased to 400 CWE BPD, and subsequently, to 600 CWE BPD with an 80% ex-boiler steam quality. The higher steam rate increased the bottom hole steam injection pressure to 3,000 psig @BHT = 608°F. Apparently increasing the steam injection pressure resulted in a decrease in the steam quality; for, the saturated steam at such pressure should have had a BHT ≈ 665°F.

The continuous steam injection was suspended during March-June, 1994 due to the repair and maintenance of the steam generator. It was resumed in mid-July, 1994 and continued until February, 1995. However, minor problems with the generator persisted, and this resulted in several occasional disruptions in the steam injection. Despite such operational problems, an average stabilized steam injection rate of 566 CWE BPD could be maintained. However, the steam quality at the wellhead decreased to 65% during this phase. This resulted in a higher bottomhole injection pressure of 3220 psi, which is above the critical pressure of steam, 3206 psi. At such pressure, the difference between the hot water and steam ceases to exist. Also, there was a significant temperature drop at the bottomhole -- the BHT decreased to 471°F. It is possible that during this phase of steam injection, almost all of the steam condensed to hot water when it reached the target formation.

It is obvious from the BHP and BHT monitored at the production and observation wells that these wells responded -- albeit mildly -- to the steam injection pressure. However, with the exception of SP3, there appears to be no significant BHT responses at other wells. Even at SP3, the rise in the BHT is rather small. Therefore, it appears that either the heated oil bank did not reach the production wells or it dissipated most of its heat by the time it reached the production well. If one assumes the former as the case, it implies that the hot oil bank was driving the cold oil ahead of it, and that, had the production wells been more closely spaced, the heated oil would have broken through the production well. However, a look at the water-cut responses at the production wells seems to provide support for the latter scenario as well; for, the increased water-cuts occurred, consistently, particularly at wells SO and SP3. That is, the condensed steam at front contributed to the increased water-cut.

The actual pilot performance in terms of the oil recovered are summarized in Table 4 for both CSS and steamflood. During the steamflood, 26180 bbls of oil was produced with 81394 CWE bbls of steam, resulting in a favourable OSR of 0.32. Well-by-well cumulative oil and water production for the entire test period shows SP4 to be the most prolific well followed by SP2. Notice that in all wells, a low WOR in the range of 0.02-0.43 was achieved (see Figure 11).

The foregoing production performance data raise more questions than answers:

- What was the effective steam quality when it hit the formation face at the depth of 4428ft?
- How effective was the insulated tubing in reducing wellbore heat loss?
- How did the vicinities of production wells responded to the steam flood in terms of water cut and reservoir heating?
- What role did the fracture caused by acidizing play? How was the fracture oriented?

An attempt has been made to address these questions by a simulation history match and sensitivity analysis.

Simulation History Match and Sensitivity Analysis

An integrated approach was employed in the simulation study which included not only the reservoir processes but also the surface facilities and the wellbore effects. Two simulators-- SIMAX and STMG -- both developed by the Japan Oil Engineering Company, a member company of the JEORA, have been used to match steam injection system and performance history, respectively.

Surface and Wellbore Heat Losses. As the success of a steamflood hinges on the quality of the steam, it is important the quality of the steam delivered at the wellhead is of high quality. The quality of the steam depends on pressure, temperature and the quality of feed water. In this pilot, the steam injection pressure and temperature were monitored regularly, and occasionally, the steam quality was estimated. The heat loss within the surface line was within the normal limit, and the estimated steam-saturation temperature agreed reasonably well with the measured wellhead temperature (WHT).

In the wellbore, the BHT was lower than the WHT and the BHP was higher than the wellhead pressure (WHP). In all cases, the BHT was lower than the estimated steam saturation temperature at the corresponding saturation pressure. This suggests the existence of hot water at the bottom hole and that, some of the steam condensed to hot water in its trip downhole within the insulated tubing itself.

The base case input parameters for wellbore heat loss calculations are given in Table 2. Four approaches were undertaken: (i) match both BHT and BHP using the same thermal conductivity, (ii) match BHP only by modifying the thermal conductivity, (iii) match BHT only by modifying the thermal conductivity, and (iv) match both BHT and BHP by using an average of thermal conductivities used in (ii) and (iii).

The approach (iv) using the Hagedorn and Brown[3] method yielded the best BHP and BHT match (see Figures 12 & 13). Both BHT and BHP matched within 20°F and 50 psi, respectively. However, it is obvious that the variable that is key to obtaining a good match was the thermal conductivity of the insulation. Our studies suggest that, in reality, it was much higher than 0.006 Btu/hr.ft.°F as was originally specified. As per the history match, the thermal conductivity of the insulated tubing varied widely between 0.05 Btu/hr.ft.°F and 0.4 Btu/hr.ft.°F. Interestingly, the match also suggests that the quality of the thermal insulation of the tubing deteriorated with time and injection pressure (see Figure 14). Also, it is possible that insulation damage had occurred due to thermal fatigue as evidenced by the further insulation deterioration when the steam injection was resumed in July, 1994. It is to be noted that the water in the annulus was boiled off continuously, and this might have also caused a small fraction of heat loss.

As has been noted, during the period generator was being repaired, the injector, SI, was put on production. During this period, produced gases at SI exhibited an increase in CO_2 and H_2S content due to thermal interaction among steam/hot water, oil and the rock accompanied by a corresponding decrease in CH_4 content (see Figure 15). The average CO_2 content during this period was about 12%. The production of such gases may also result in the formation of scales on the tubing surface and contribute to some increase in the heat loss.

The primary question remains: *what was the steam quality at the bottomhole?* Without question, retaining the steam quality at the formation depth has been the biggest operational challenge. Not only the formation depth is high, but, also the steam injectivity was lower than as estimated -- often requiring much higher than usual steam injection pressure. Thus, possibility of benefitting from the steam latent heat, if any, is slim. Nevertheless, our simulation history match suggests that although operational conditions were such that in most cases the steam condensed to hot water before it hit the target formation, on few occasions it was possible to retain at least some steam quality until the steam reached the formation face. Occasions that permitted it to happen were high steam injection rate (≥ 617 CWE BPD) and high generator steam quality (≥80%). Figure 16 shows a plot of steam quality versus formation depth for a 4-day continuous steam injection period when some steam quality was probably retained at the formation face.

Production and Injection History Match

The primary emphasis in the simulation study was to match (i) pressure and temperature based on the actual production and injection data, and (ii) water breakthrough at each well. For the material balance calculations, two models -- cylindrical and perpendicular parallelepiped --are used. The former analyses the sensitivity of the reservoir pore volume to pressure, and the latter, estimates the reservoir extent along N-S to adequately treat the fracture between SP1 and SI. The estimated initial oil-, water- and gas-in-place are listed in Table 5.

The grid system used in the simulation is shown in Figure 17. Presented in Figure 18 are the relative permeability curves that best describe the flow in this case. These curves are based on Frizzell's correlations[4] for S_{wir} and S_{or}. The relative permeability curves have been shifted by 5% towards high water saturation so as to delay the water cut. Also, k_h was modified along x- and y-directions to reflect the preferential flow of the injected fluid along N-S direction, while retaining the original mean permeability ($\sqrt{[k_x k_y]}$) values. The oil viscosities as a function of pressure and temperature are given in Figure 19.

Treatment of the Fracture. During the preliminary history matching, the simulator predicted an excessive pressure build up due to continuous steam injection. However, in reality, such was not the case; for, the pressure which had built up initially soon leveled off during the continuous injection phase. This anomaly between the predicted and observed pressure behavior led to further investigation of the nature, extent and the role of the fracture between SP1 and SI. In particular, the following three possibilities have been investigated:

a) the fracture progressively extends farther north and south during the continuous steam injection and it closes when the injection is stopped
b) the permeability anisotropy along N-S direction is stronger
c) dilation of the fracture takes place during the continuous injection of steam

It was found that if a fracture four times the distance between SP1 and SI was assumed, a good pressure match was obtained. In the second case, the permeabilities assigned in the N-S direction are 10 times greater than E-W direction so that diffusion of the excess pressure occurs in the N-S direction. After some trials, the match was further improved by local permeability refinement. For example, when the permeabilities around SO and SP2 were reduced, a good pressure history match was obtained.

The third case is based on the premise that when the injection pressure exceeds the dilation pressure, the rock compressibility increases by 1-2 orders of magnitude because of the plastic characteristics of the rock[5]. However, such characteristics are usually associated with unconsolidated formation, and may not hold good for deep limestone formations which are compact. Hence, the third possibility was discounted.

The final history match of pressure and temperature has been carried out based on possible combined effects of the first two possibilities; that is, the fracture is extended beyond the pilot area and strong permeability anisotropy exists.

A preliminary evaluation of the temperature log ran in the newly drilled evaluation well, SE, suggests yet another possibility with respect to the nature and the extent of the fracture that communicates between SI and SP1. The temperature log (see Figure 20) conducted after 87 days of the continuous steam injection indicates a residual heat effect below Upper zone extending downward as far as to 4575 ft (1395m). Within this zone, the temperature distribution deviates significantly off the formation temperature-gradient of 0.041°F/ft (shown by the dashed line in Figure 20). This leads to the speculation that the fracture caused by the steam injection may have opened vertically downward causing a significant amount of the condensed (hot) water to be stored in the bottom zone. In other words, there has been a significant heat loss to the underburden. However, this possibility will be further investigated as and when other data from the evaluation well are gathered and analyzed.

Final History Match. The results of the final history match of pressure and temperature are shown in Figures 21-25 for wells SI, SO, SP2, SP3 and SP4. In general, reasonably good history matches have been obtained for each well. Final results of the history match are summarized below for the entire life of the pilot:

	Actual	*Calculated*
Cum. Steam Injected (M CWE bbl)	82.65	82.14
Cum. Oil Production (MSTB)	38.28	38.80
Cum. Water Production (M bbl)	2.95	2.39

The cumulative oil production figures also account for 7.78 MSTB of oil which was produced from SP2, SP3, SP4 and SO when the steam injection was suspended. The actual water production figure includes the formation water, mainly from SP2.

The areal distribution of pressure, temperature and water saturation are shown in Figures 26-28 at the end of the first continuous steam injection phase. The pressure rose rapidly along the fracture line indicating a preferential flow along N-S direction beyond the pilot area. The temperature distribution, too, suggests that the heated area was narrow and was influenced by the fracture. No temperature increase at wells other than SP1 and SI is indicated. As with temperature, the high water saturation region was influenced by the fracture as well. The water invasion through the fracture face was limited and the maximum incremental water saturation around fracture grid blocks was <10%. At the end of history, i.e., after 729 days, it shows that the water had broken through at SP3 and SO (see Figure 29)

Summary

We have presented a critical evaluation of a steamflood pilot project carried out as an international collaborative project between the JNOC and TPAO.

The reservoir and operational conditions were severe; target formation was a carbonate at a depth of 4430ft. To our knowledge, it makes it the deepest steamflood in a carbonate reservoir.

The major challenge was to maintain the steam injectivity while retaining the steam quality as much as possible. Also, the fracture caused prior to the steam injection during acidizing called for a review of pilot operations strategy. Problems associated with the steam injectivity and quality have been discussed and analyzed with the help of actual performance data and simulation studies. To obtain a satisfactory history match, special treatment of the fracture had become necessary.

In spite of the severity of operational conditions and problems, a net incremental recovery of 30.5 MSTB oil, attributed to the thermal processes -- CSS and steamflood, was possible Overall, attractive OSRs: 3.42 in the CSS and 0.32 in the steamflood were achieved.

Nomenclature

h = *net pay thickness*
k = *absolute permeability*
k_h = *horizontal permeability*
k_x = *horizontal permeability in x-direction*
k_y = *horizontal permeability in y-direction*
S_o = *oil saturation*
S_{wir} = *irreducible water saturation*
ϕ = *porosity*
μ_o = *oil viscosity*

Acknowledgement

Authors thank the JNOC and TPAO for the permission to present this paper.

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SI Metric Conversion Factors

°API x 141.5/(131.5+°API)	= g/cm^3
bbl x 1.589873	= E-01 = m^3
Btu x 1.055056	= E+00 = kJ
cp x 1.0*	= mPa.s
ft x 3.048*	= E-01 = m
ft^3 x 2.831685	= E-02 = m^3
°F (°F-32)/1.8	= °C
in. x 2.54*	= E+00 = cm
md x 9.869233	= E-04 = μm^2

*Conversion Factor is exact.

TABLE 1- Summary of Ikiztepe Oil Field

Field History		
Production Period	1976 -1982	
Production Method	Pumping	
Number of Well	10 Wells	
Cumulative Oil Production	88 MSTB	
Oil Recovery	< 1 %	
Status	Suspended	
Reservoir Description		
Rock Type	Carbonate Rock (Sinan Formation)	
Depth	1,350 m (@ 880ms.s.)	
Thickness	100 m - 150 m (8 Sublayers)	
Reservoir Press.	1,841 psig	
Temp.	120 °F(@ 880ms.s.)	
G.O.C	844 ms.s.	
O.W.C	990 ms.s.	
Porosity	11 - 23 %	
Swi	12 - 30 % (Swir)	
Test Zone	Upper Porous Zone	
Depth	1,350 m (@ 880 m s.s.)	
Thickness	13 m - 22 m	
Porosity	15 - 23 %	
Permeability	50 - 400 md	
Swi	14 - 17 % (Swir)	
Fluid Properties		
Bubble Point Press.	900 psig	(@ 880 ms.s.)
Oil Gravity	10 -12 °API	(STO)
Oil Viscosity	936 cp	(@ 1,841psig, 120 °F)
	2,000 -15,000 cp	(STO)
Rs	95 scf/bbl	(@ 1,841 psig, 120 °F)
Bo	1.056 vol/vol	(ditto)
Bg	0.01 vol/vol	(ditto)
Formation Water Salinity	45,000 ppm	

TABLE 2- Thermal Properties of Insulated Tubing

Length of Well Tubing	: 4428	ft
Inner Diameter of Inside Tubing	: 2.44	in
Relative Roughness of Inside Tubing	: 0.001	
Outer Diameter of Inside Tubing	: 2.875	in
Thermal Conductivity of Inside Tubing	: 39.2	Btu/(ft.hr. °F)
Outer Diameter of Insulation	: 4.05	in
Thermal Conductivity of Insulation	: 0.006	Btu/(ft.hr. °F)
Outer Diameter of Outside Tubing	: 4.5	in
Thermal Conductivity of Outside Tubing	: 39.2	Btu/(ft.hr. °F)
Inner Diameter of Casing	: 5.79	in
Outer Diameter of Casing	: 6.63	in
Thermal Conductivity of Casing	: 39.2	Btu/(ft.hr. °F)
Outer Diameter of Cemented Hole	: 8.63	in
Thermal Conductivity of Cement	: 2.08	Btu/(ft.hr. °F)
Temperature of Surface Ground	: 59	°F
Temperature Gradient of Formation	: 0.0142	°F/ft
Thermal Conductivity of Formation	: 1.092	Btu/(ft.hr. °F)
Specific Heat of Formation	: 0.203	Btu/(lbm. °F)
Density of Formation	: 137.1	lbm/cub.ft

TABLE 3- Summary of Steam Injection System

Water Analysis	Source Water	Treated Water
Turbidity (NTU)	0.70	0.50
SS (mg/l)	2.00	1.00
pH (@25 °C)	8.20	8.40
Total Hardness ($CaCO_3$ mg/l)	198	0.1
TDS (mg/l)	314	391
Na^+ (mg/l)	14.8	128
Ca^{2+} (mg/l)	48.33	0.20
Mg^{2+} (mg/l)	25.52	0.10
$Fe^{2+/3+}$ (mg/l)	0.31	0.05
Cl^- (mg/l)	4.80	12.40
SO_4^{2-} (mg/l)	7.0	37
SiO_2 (mg/l)	32.4	32.5

Specification of Generator

Max. Injection Rate (CWEBBL/D)	660
Max. Pressure (psig)	2,500
Max. Temperature (°F)	667
Steam Quality (%)	80

TABLE 4 - Actual Performance of Pilot Test

Operation		Steam Flooding
Huff & Puff	Test Period	Apr. 7 - Sep. 12 1993
	Injection Rate	72 - 216 CWEBD
	Cumulative Injection	1,260 CWEBBL
	Cumulative Oil Production	4,315BBL (OSR 3.42)
Flooding	Test Period	Oct.19 1993 - Feb.16 1995
	Injection Rate	210 - 600 CWEBD
	Cumulative Injection	81,394 CWEBBL
	Cumulative Oil Production	26,180BBL (OSR 0.32)

TABLE 5 - Calculated Initial In Place within the Test Pattern

	Layer 1	Layer 2	Layer 3	Total
Initial Oil In Place (MSTB)	70.68	31.53	153.05	255.26
Initial Gas In Place (MMSCF)	6.45	2.90	14.68	24.03
Initial Water In Place (MBBL)	14.10	6.74	27.38	48.22

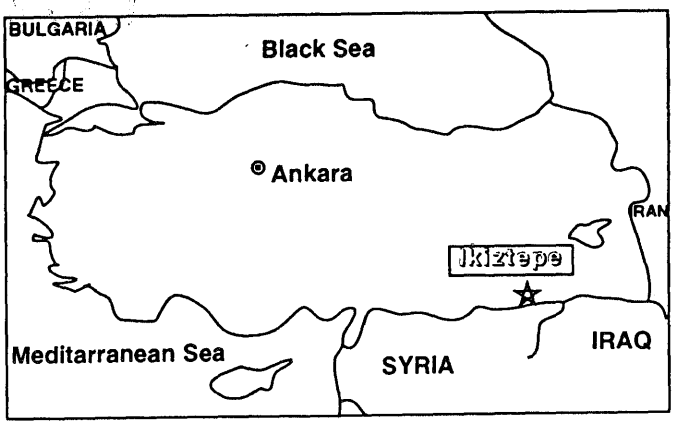

Fig. 1 Location Map of Ikiztepe Oil Field

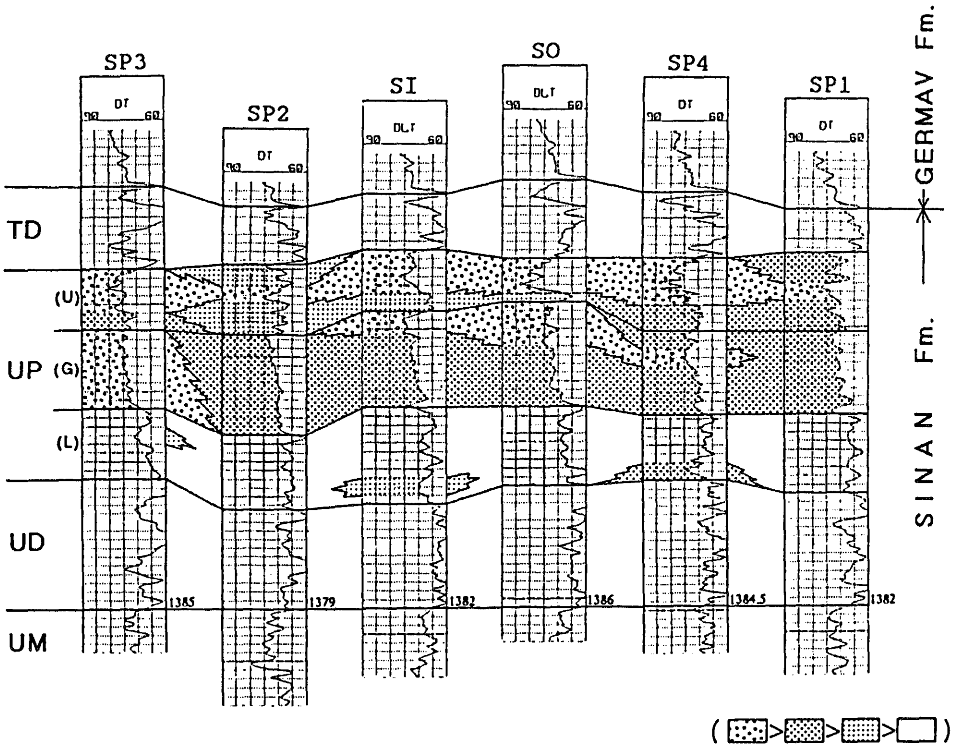

Fig. 2 Stratigraphic Interwell Correlation

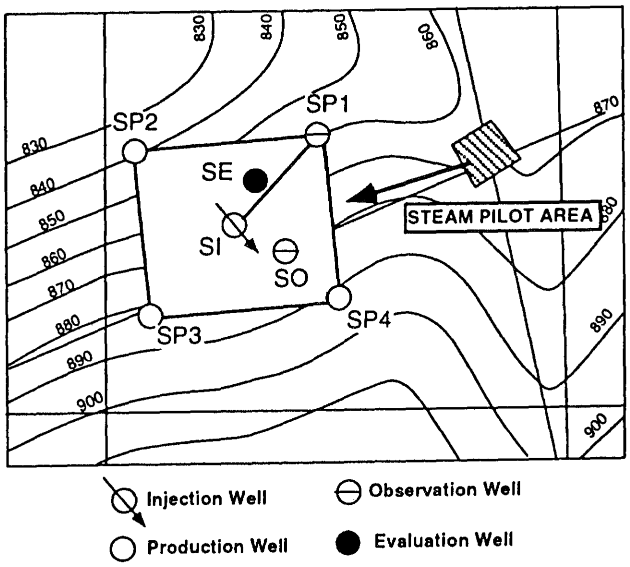

Fig.3 Pilot Test Pattern

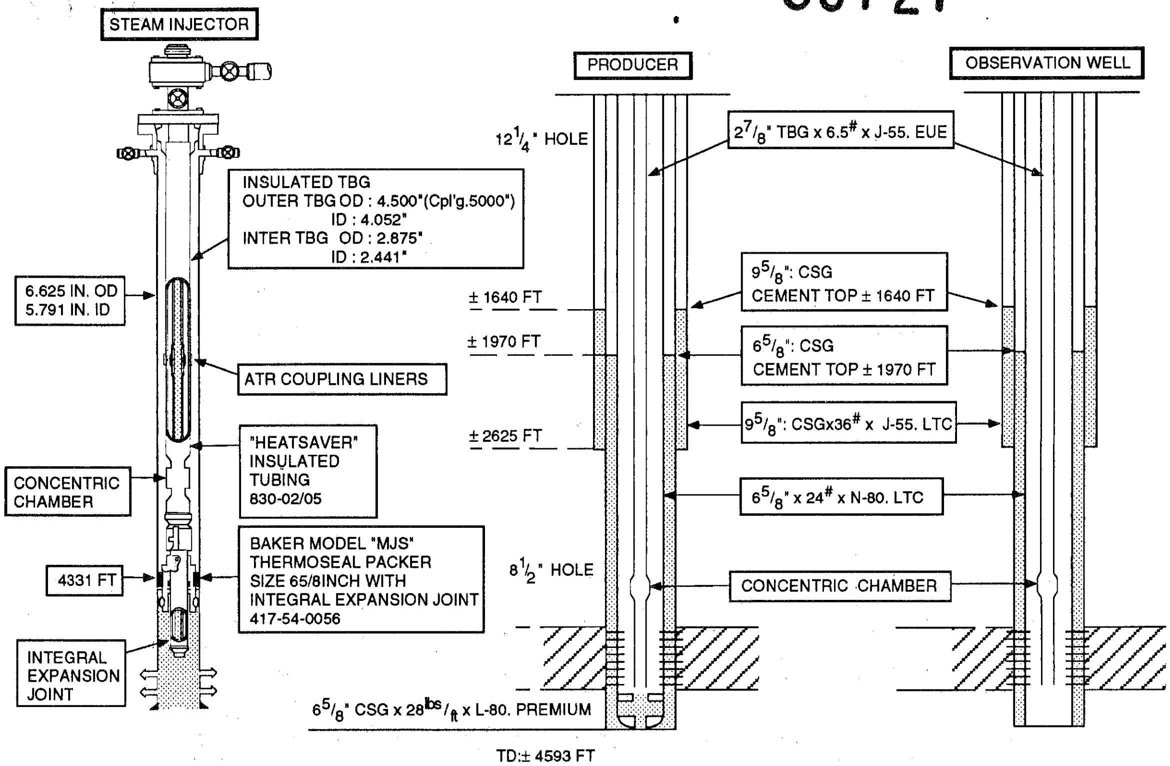

Fig.4 Well Completion Schematics

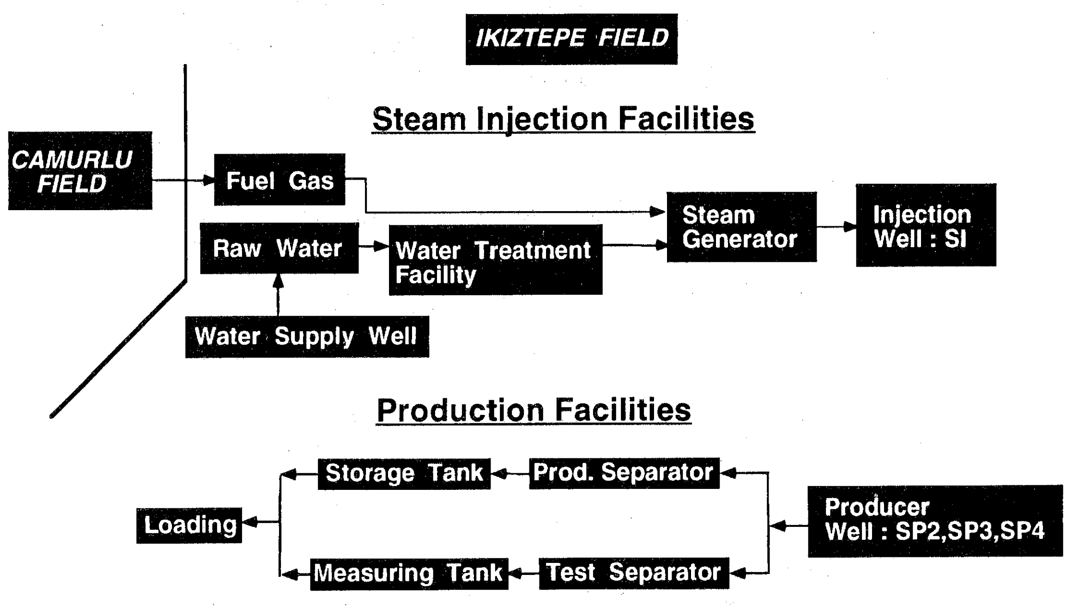

Fig. 5 Flow Diagram of Injection/Production Facilities

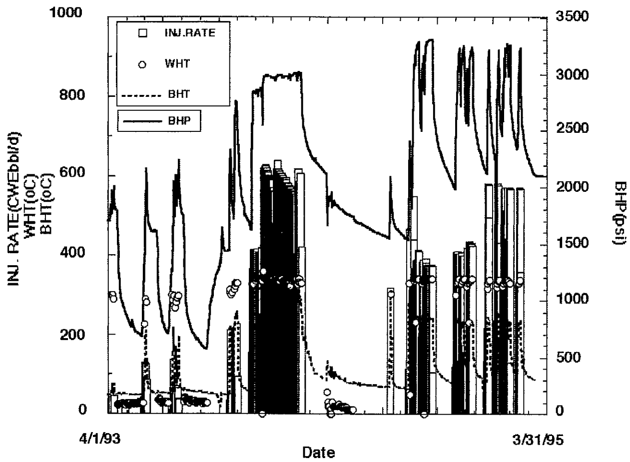

Fig. 6 Injection Performance of SI

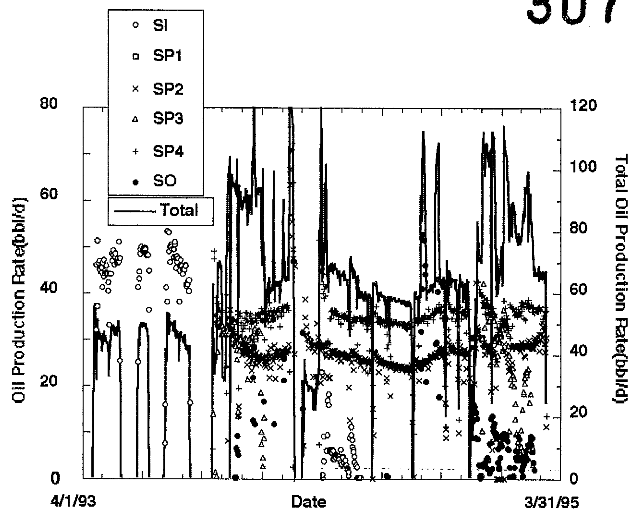

Fig. 7 Oil Production Performance

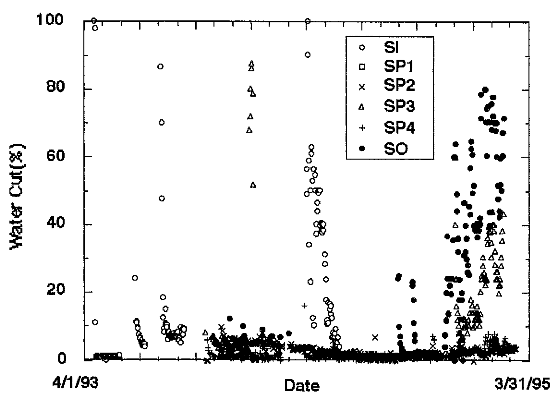

Fig. 8 Water Cut Performance

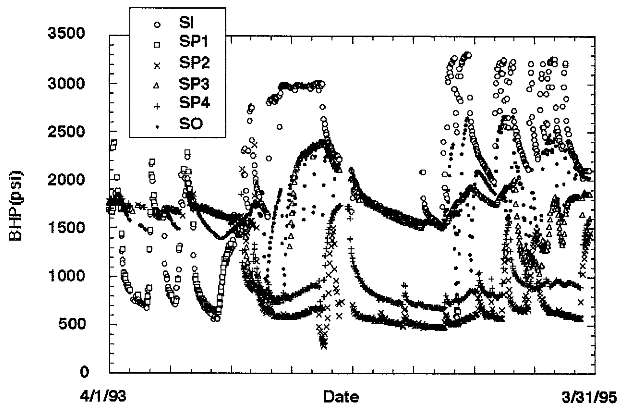

Fig. 9 Bottomhole Pressure Performance

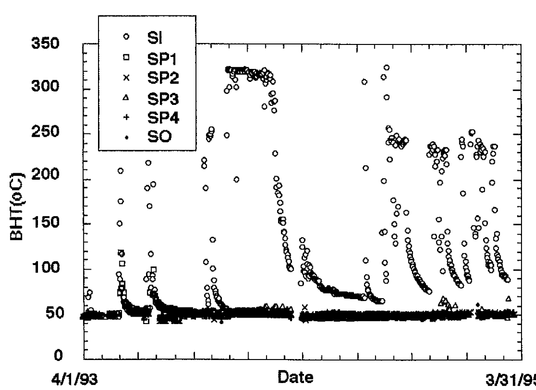

Fig. 10 Bottomhole Temperature Performance

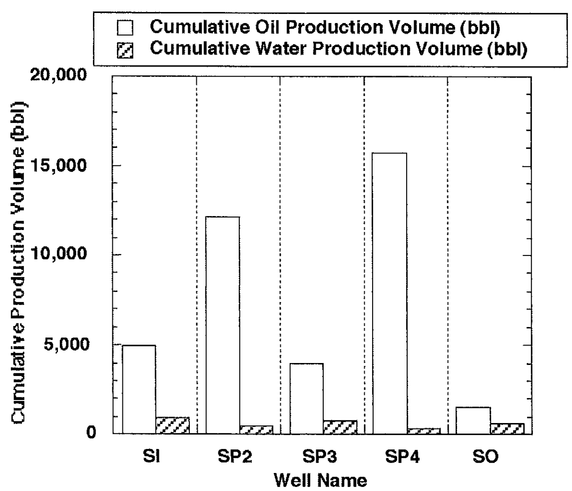

Fig. 11 Cumulative Production Volume

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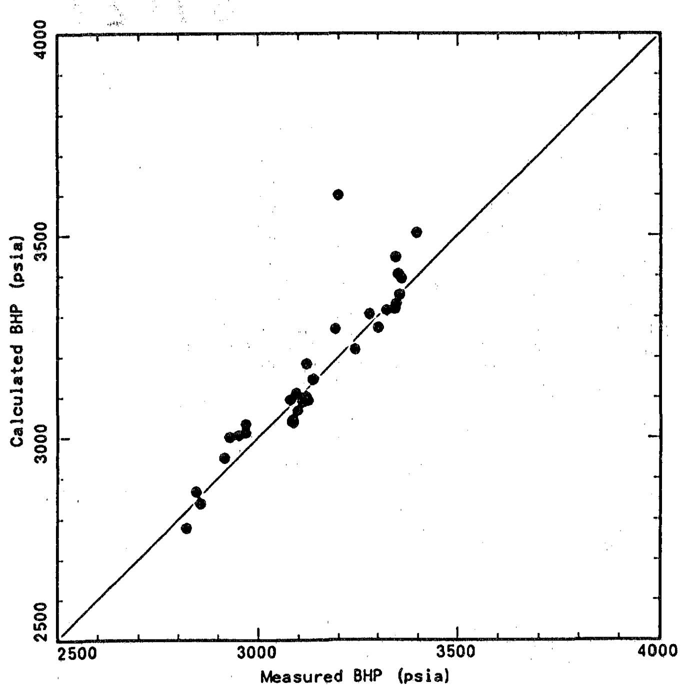

Fig. 12 BHP Match (Hagedorn & Brown Method)

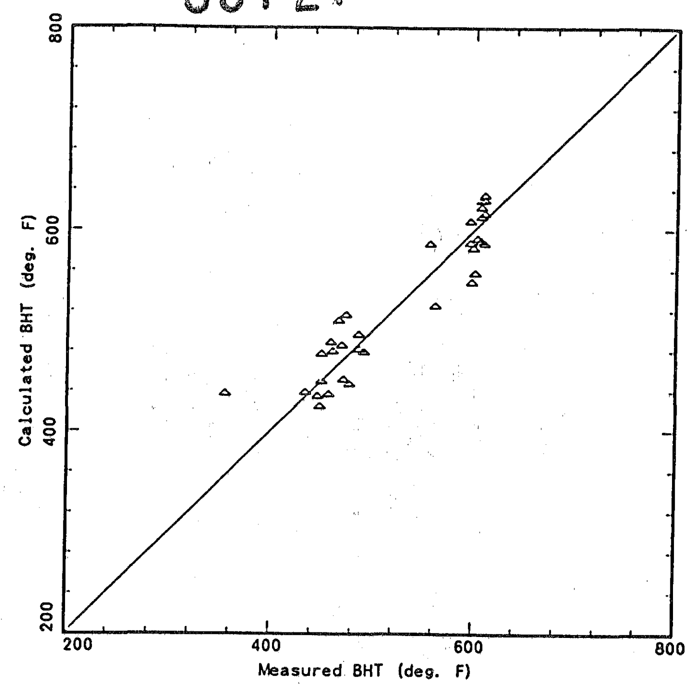

Fig. 13 BHT Match (Hagedorn & Brown Method)

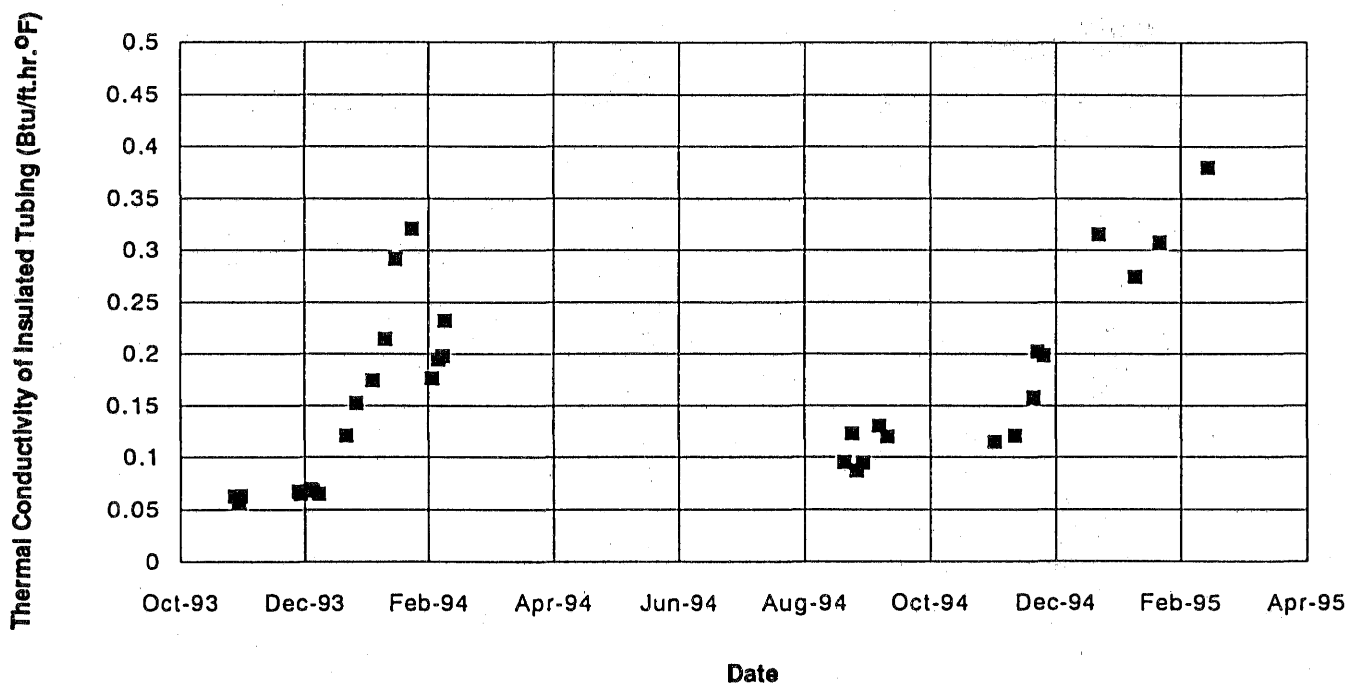

Fig. 14 Chronogical Change of Thermal Conductivity of Insulated Tubing By Matching BHP and BHT

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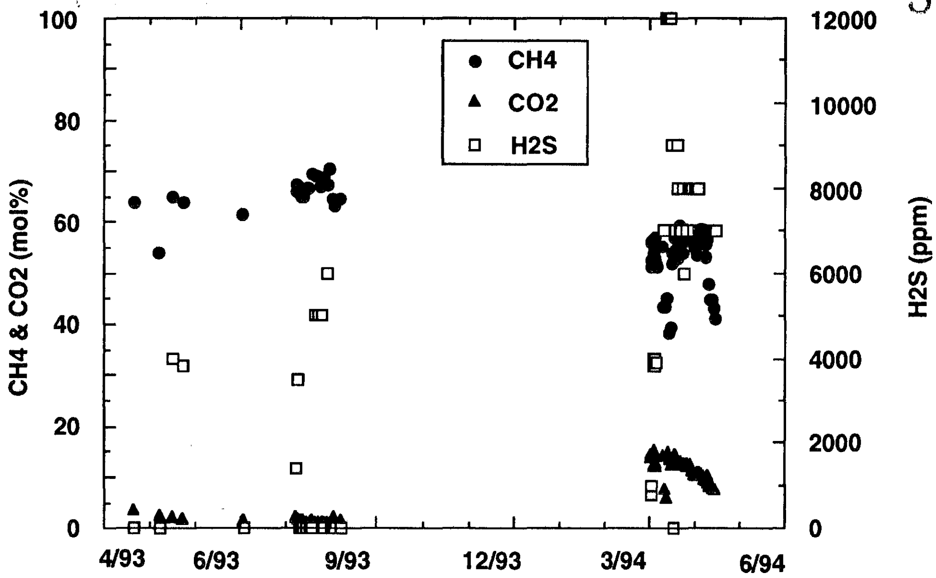

Fig. 15 Produced Gases at the Injection Well, SI

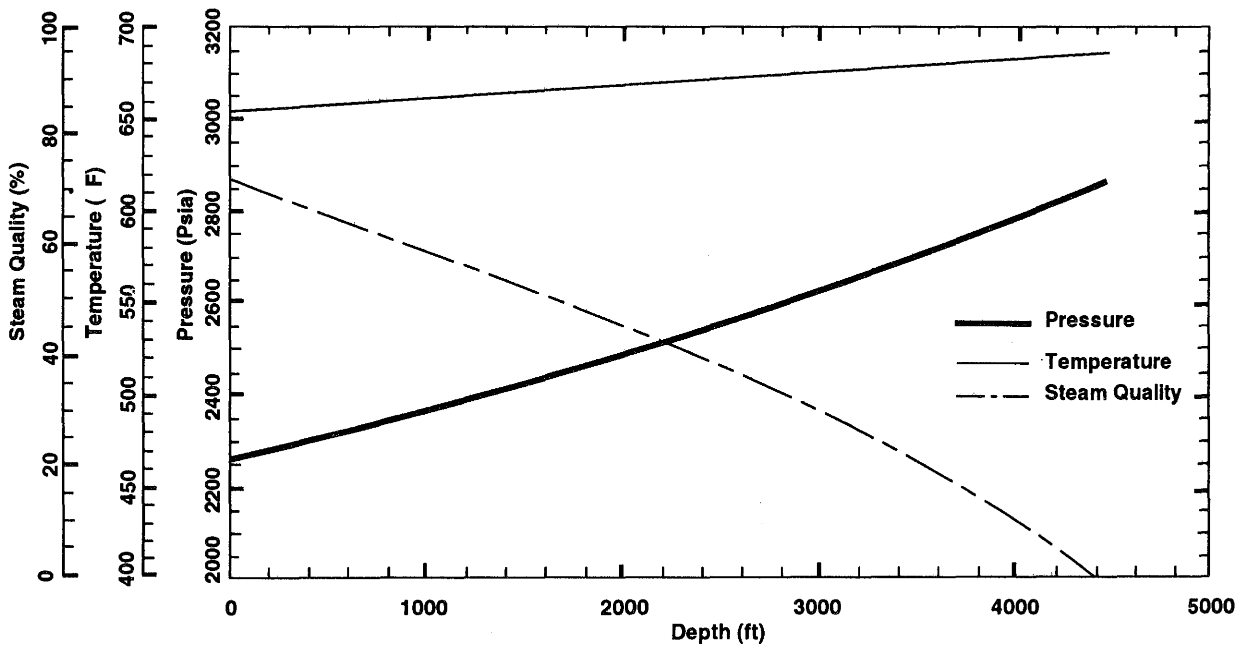

Fig.16 Depth versus Pressure, Temperature and Steam Quality

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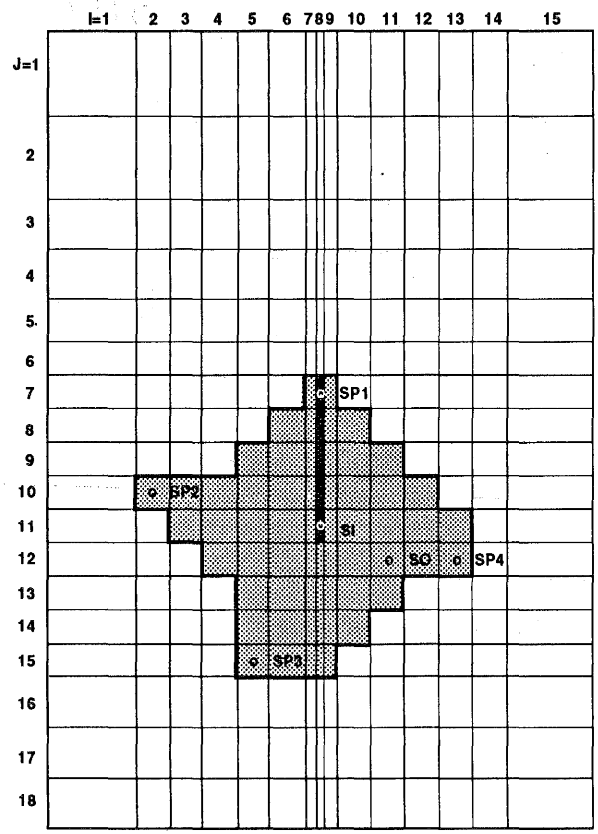

Fig.17 Grid System of Simulation Study

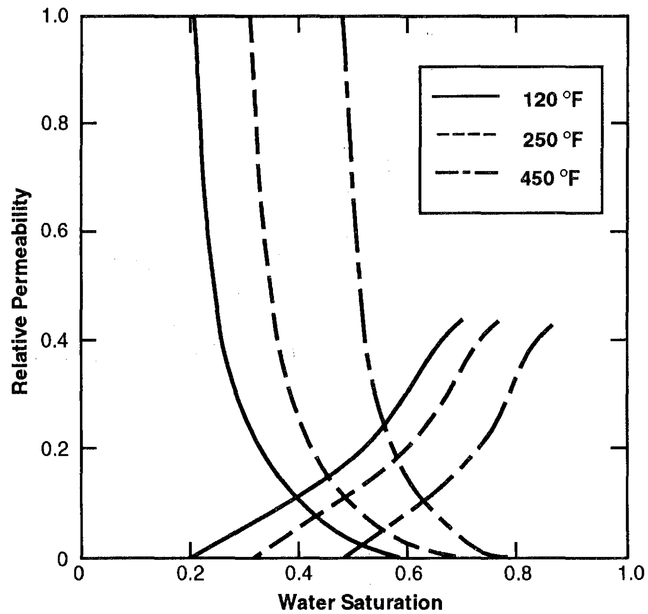

Fig. 18 Oil-Water Relative Permeability Curves

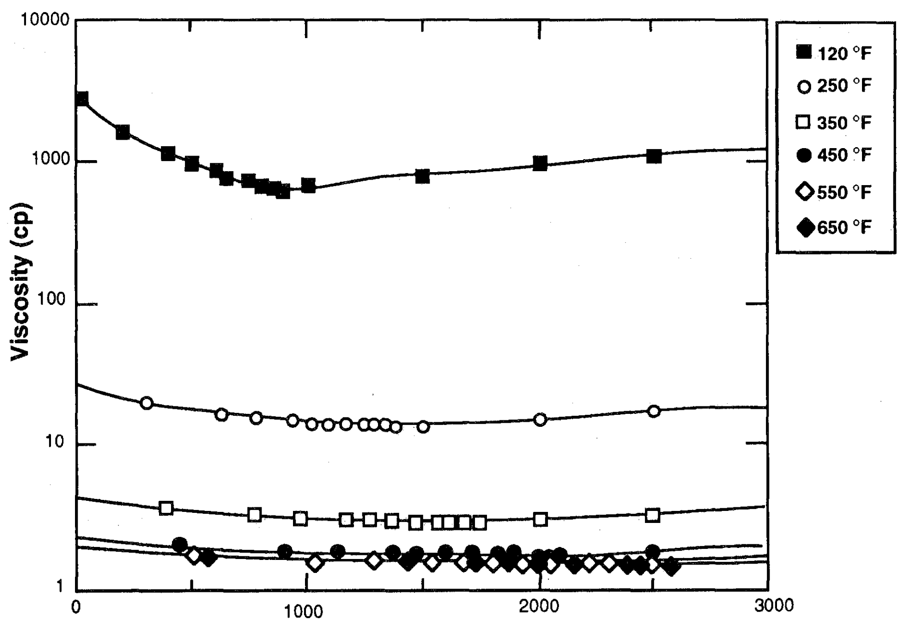

Fig. 19 Oil Viscosity at Different Temperature

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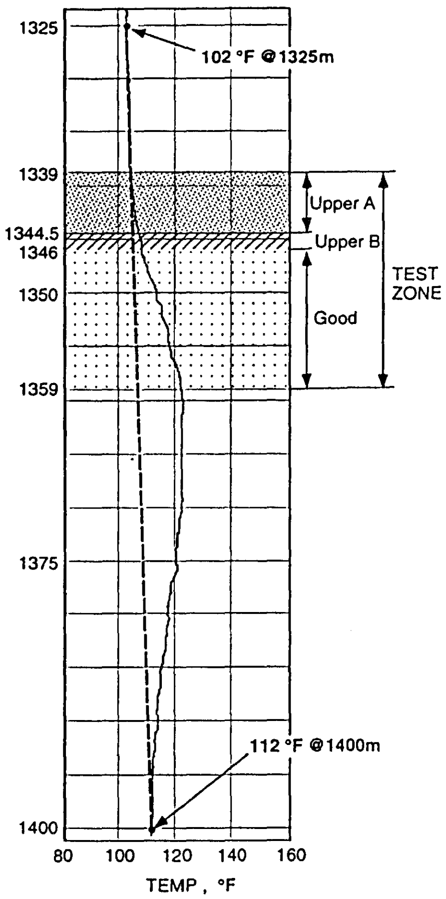

Fig. 20 Temperature Log of the Evaluation Well, SE

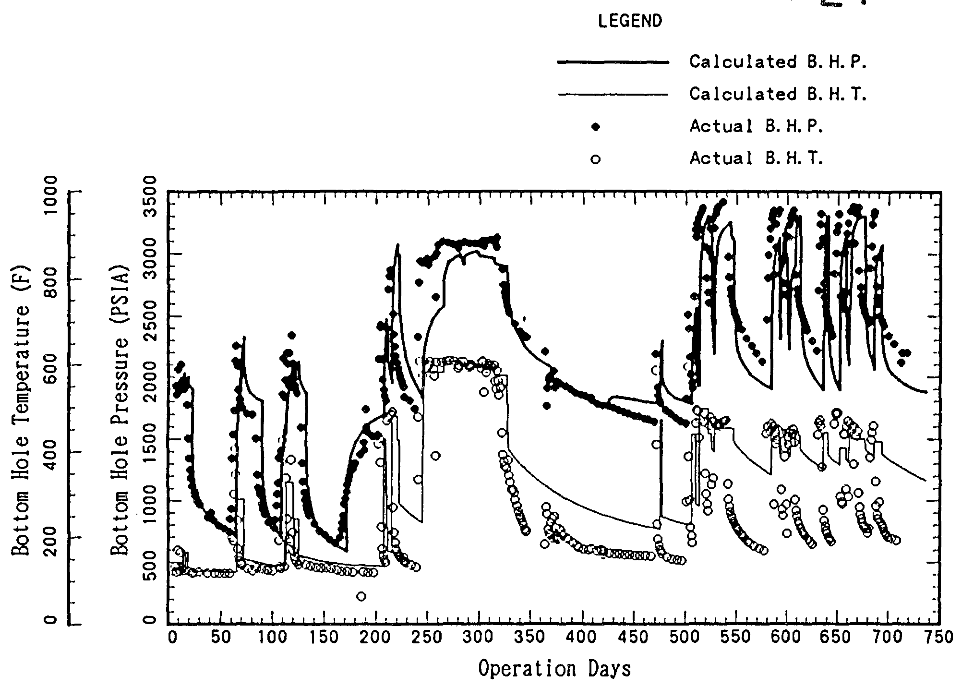

Fig. 21 Final History Match of Pressure and Temperature for SI Well

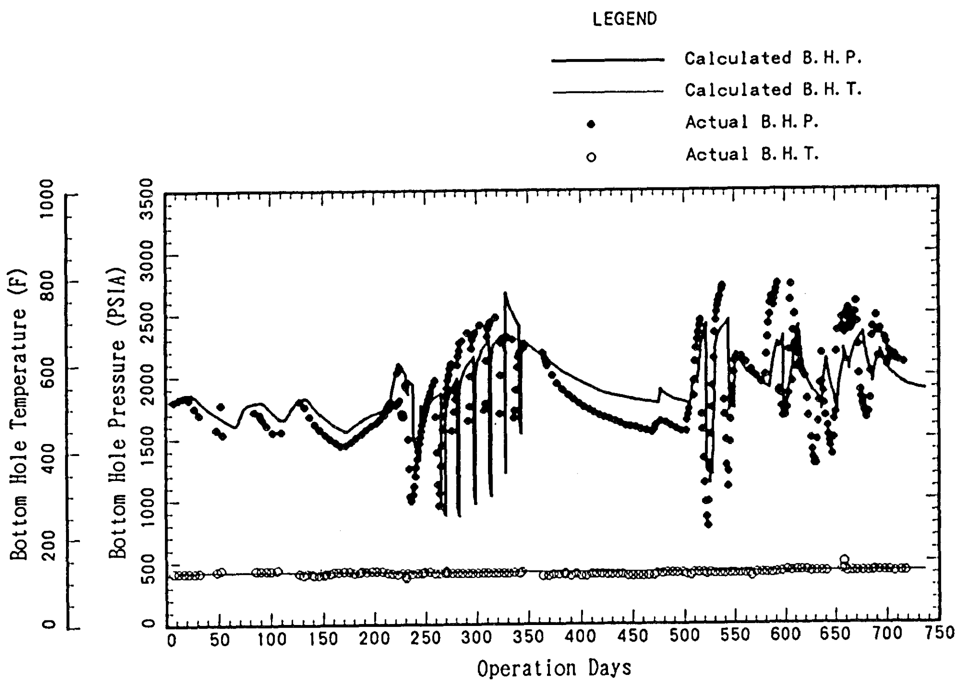

Fig. 22 Final History Match of Pressure and Temperature for SO Well

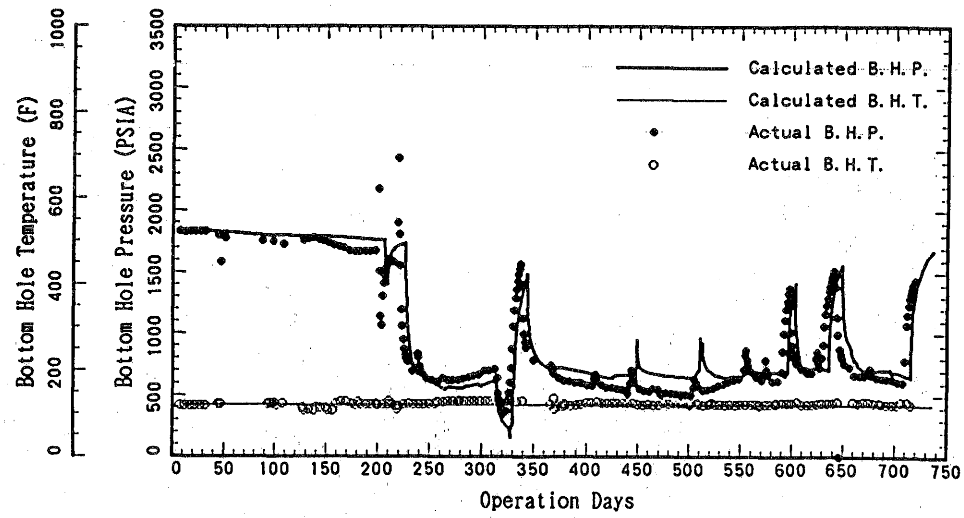

Fig. 23 Final History Match of Pressure and Temperature for SP2 Well

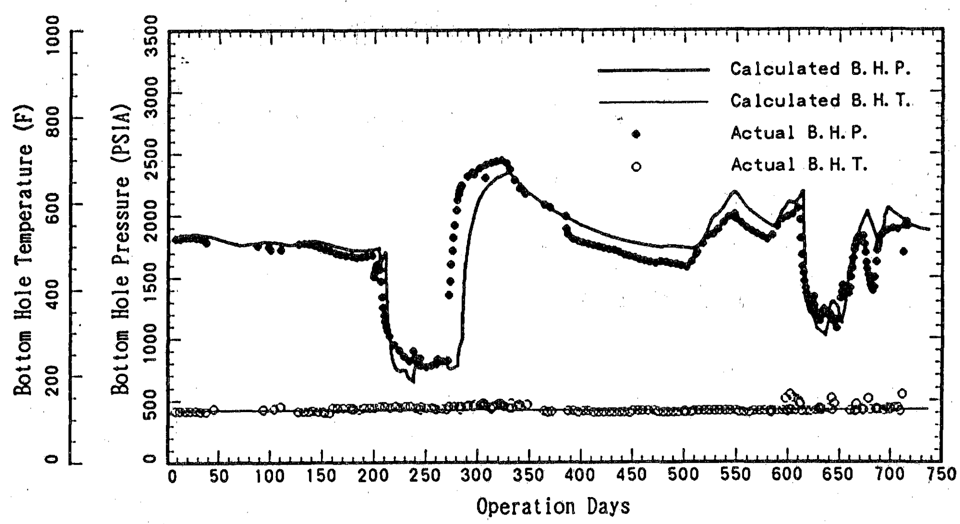

Fig. 24 Final History Match of Pressure and Temperature for SP3 Well

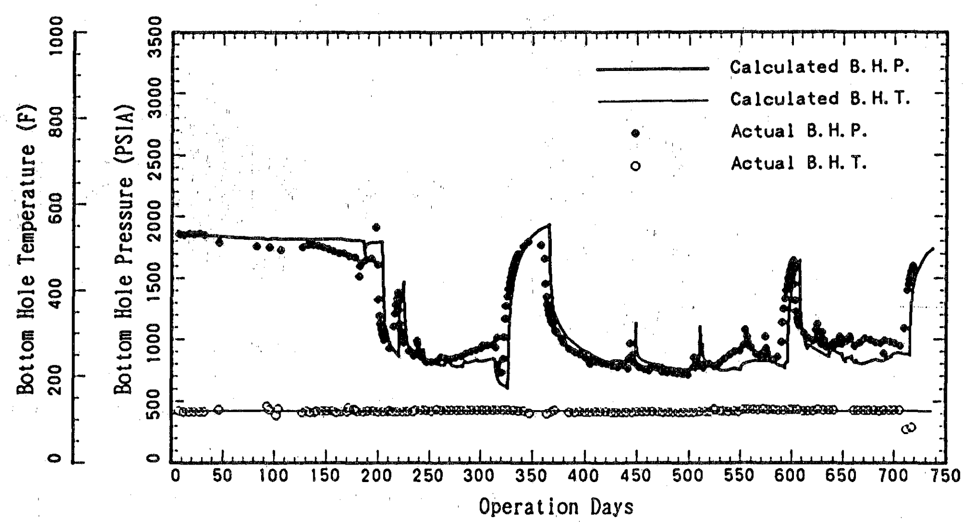

Fig. 25 Final History Match of Pressure and Temperature for SP4 Well

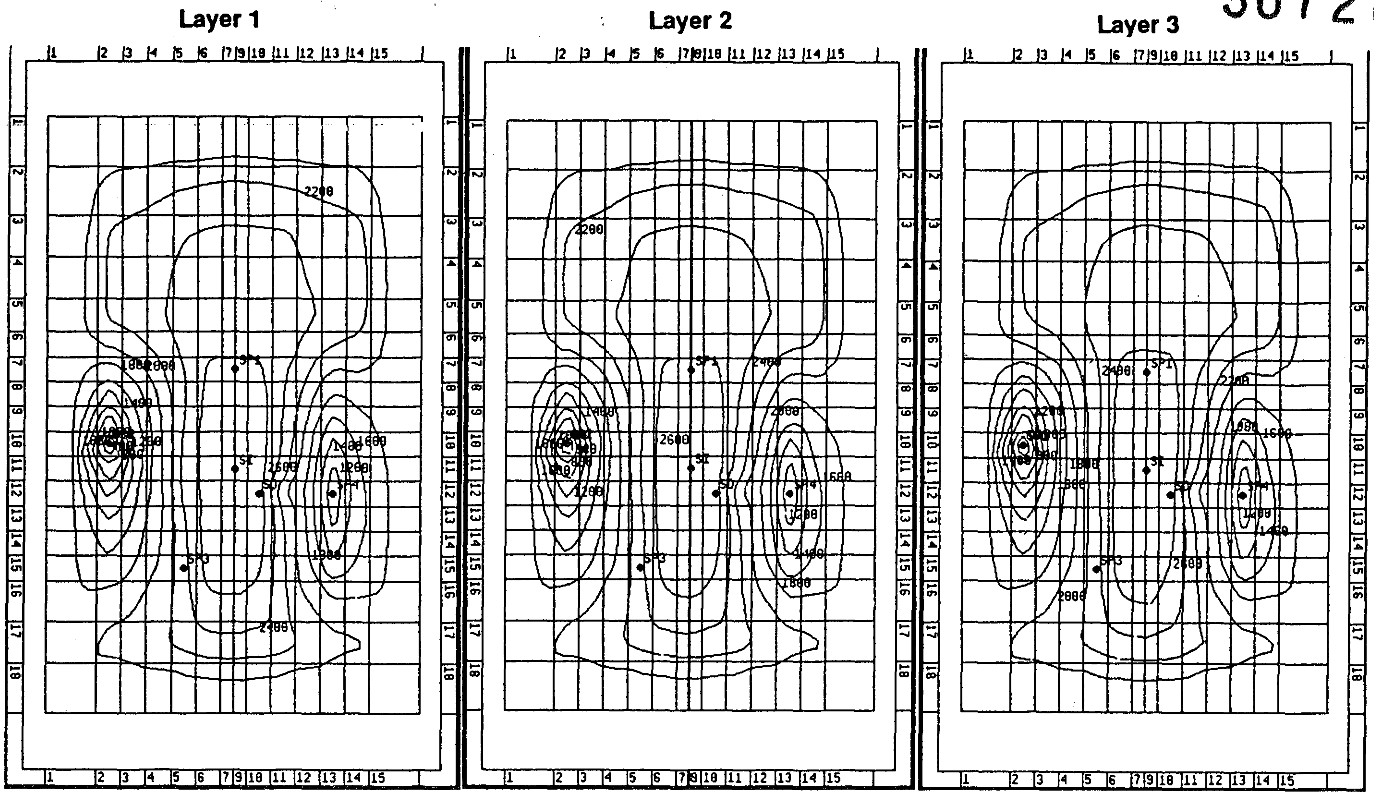

Fig. 26 Pressure Distribution Map at the End of the First Continuous Steam Injection (t=322 Days: Unit - psi)

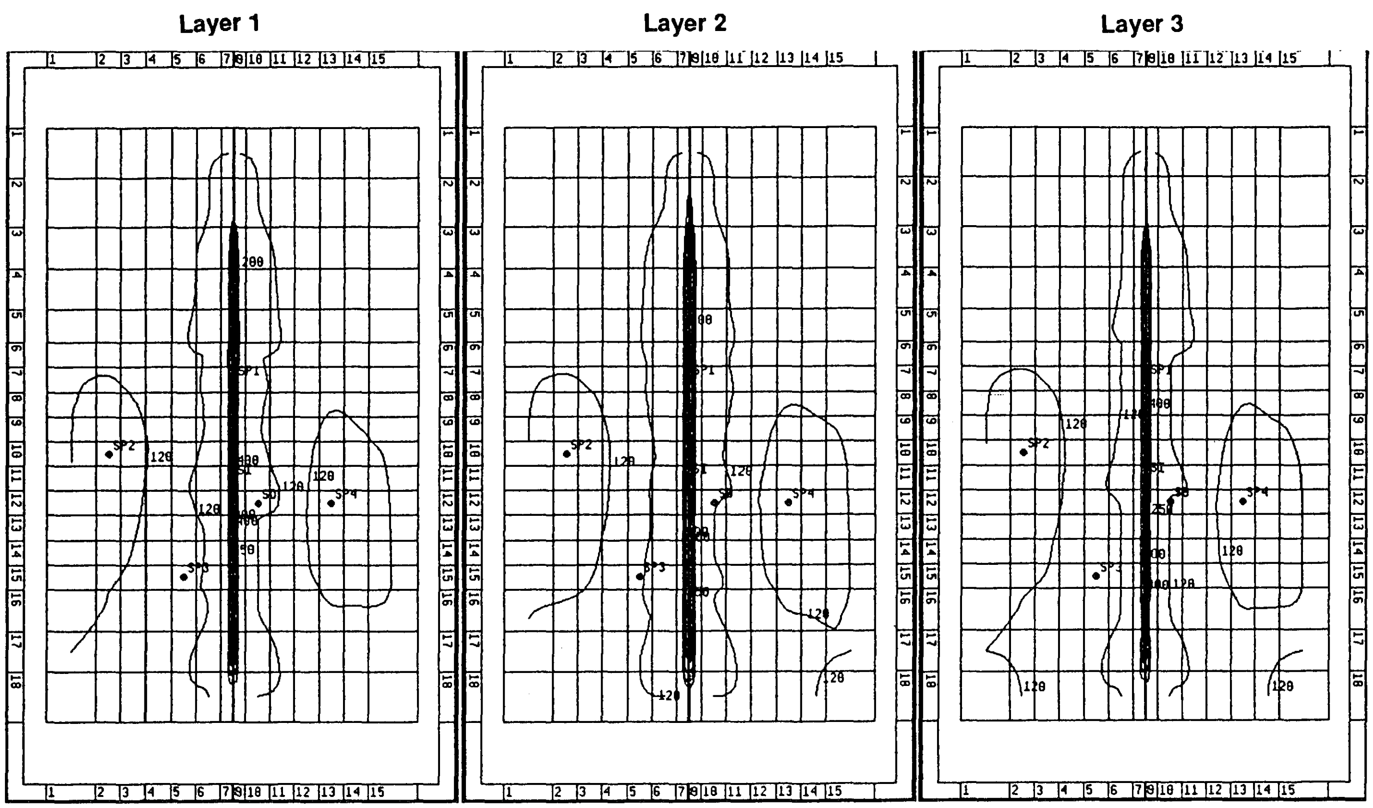

Fig. 27 Temperature Distribution Map at the End of the First Continuous Steam Injection (t=322 Days: Unit - °F)

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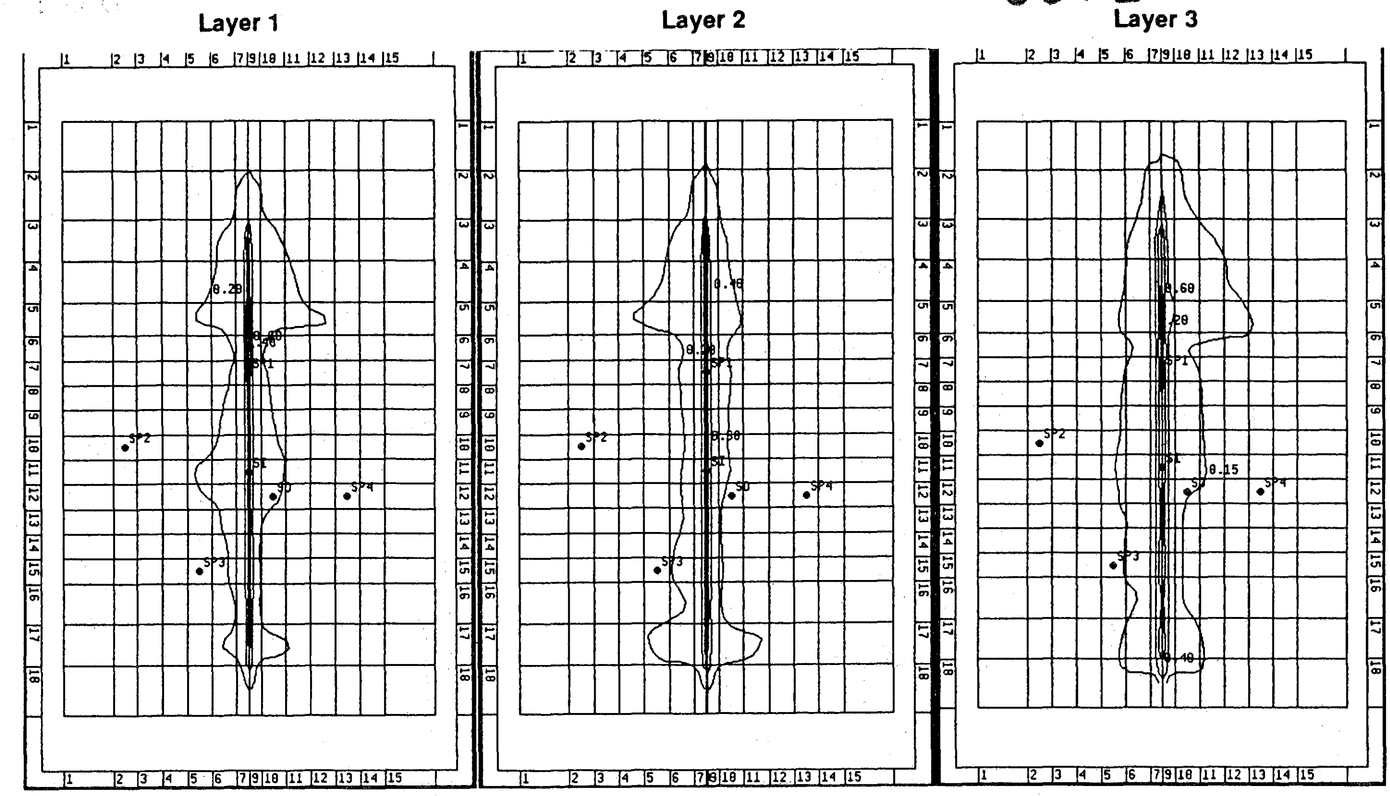

Fig. 28 Water Saturation Distribution Map at the End of the First Continuous Steam Injection (t=322 Days: Unit - Fraction)

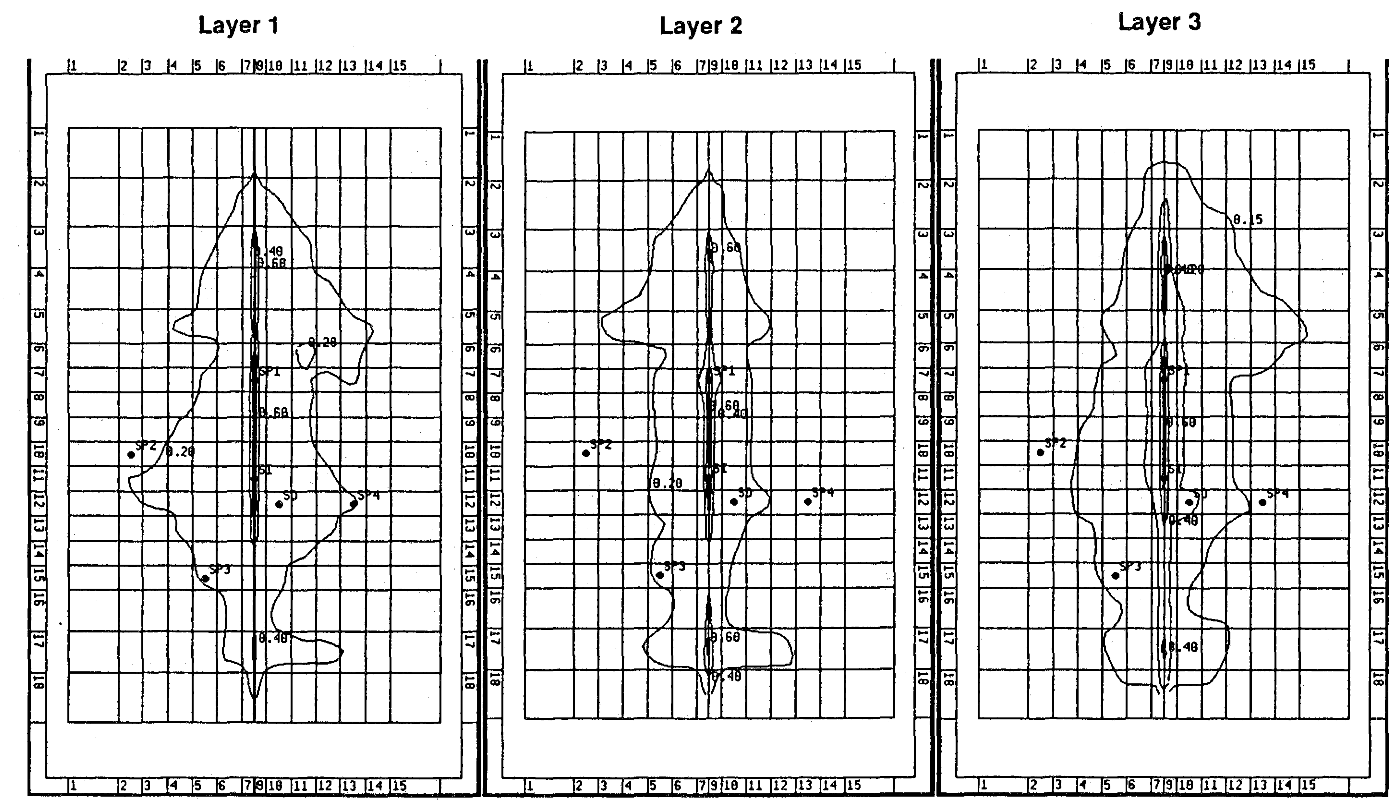

Fig. 29 Water Saturation Distribution Map at the End of History (t=729 Days: Unit - Fraction)